FINAL REPORT

WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding:
FY 2009 AVERAGE SYSTEM COST REPORT
FOR

Snohomish PUD

Docket Number: SN-PB-08-01
Effective Date: October 1, 2008

PREPARED BY
BONNEVILLE POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

September 11, 2008

This page intentionally left blank.

TABLE OF CONTENTS

Section **Page**

I. FILING DATA 1

II. AVERAGE SYSTEM COST: DETERMINATIONS 1
- A. Base Period 2006 1
- B. FY 09 (Exchange Period) ASC without New Resource Additions ($/MWh) 2
- C. FY 09 (Exchange Period) ASC with New Resource Additions ($/MWh) 2

III. FILING REQUIREMENTS....................2
- A. Introduction....................2
- B. ASC Determination Process Guidelines and Expedited Review Process.......3
- C. Explanation of Schedules....................4
  - 1. Schedule 1 – Plant Investment/Rate Base....................4
  - 2. Schedule 1A – Cash Working Capital 5
  - 3. Schedule 2 – Capital Structure and Rate of Return 5
  - 4. Schedule 3 – Expenses....................5
  - 5. Schedule 3A – Taxes 5
  - 6. Schedule 3B – Other Included Items 6
  - 7. Schedule 4 – Average System Cost ($/MWh) 6
  - 8. Distribution of Salaries and Wages....................6
  - 9. Purchased Power and Sales for Resale 6
  - 10. New Large Single Load 6
  - 11. Labor Ratios....................7
- D. ASC Forecast 7
  - 1. Forecast Contract System Costs....................7
  - 2. Forecast of Sales for Resale and Power Purchases....................7
  - 3. Forecast Contract System Load and Exchange Load 7
  - 4. Major Resource Additions....................8
  - 5. Load Growth Not Met by New Resource Additions 8

IV. REVIEW OF THE ASC FILING 8
- A. Identification and Analysis of Issues from the May 7, 2008 ASC Appendix 1 Filing 8
- B. Identification and Analysis of Issues from comments to the July 8, 2008 ASC Draft Report....................17
- C. Identification and Analysis of Issues from comments to the August 4, 2008 ASC Draft Report....................18
- D. Exchange Period ASC New Resource Additions 20

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013 20

VI. BPA STATEMENT 24

This page intentionally left blank.

I. FILING DATA

Utility	Parties to the Filing
Snohomish PUD 2320 California Street Everett, Washington 98201	A complete list of intervening parties is located at the following BPA web site: http://www.bpa.gov/corporate/finance/ascm/Docs/Intervening_Parties.pdf

Effective: October 1, 2008 – September 30, 2009
WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding

II. AVERAGE SYSTEM COST: DETERMINATIONS

A. Base Period 2006

	As Filed	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
Production Cost	$227,121,488	$226,860,355	$226,860,355	$226,860,355
Transmission Cost	$35,912,231	$35,910,723	$35,910,723	$35,910,723
(Less) New Large Single Load Costs	0	0	0	
Total Contract System Cost	$263,033,719	$262,771,078	$262,771,078	$262,771,078
Total Retail Load (MWh)	6,480,261	6,480,261	6,480,261	6,480,261
(Less) New Large Single Load	0	0	0	
Total Retail Load (Net NLSL)	6,480,261	6,480,261	6,480,261	6,480,261
Plus Distribution Losses	324,013	324,013	324,013	324,013
Total Contract System Load (MWh)	6,804,274	6,804,274	6,804,274	6,804,274
FY 2006 Base Period ASC ($/MWh)	$38.66	$38.62	$38.62	$38.62

B. FY 09 (Exchange Period) ASC without New Resource Additions ($/MWh)

	July 8, 2008 As Amended	August 4, 2008 As Revised	Sept.11, 2008 Final
FY 2009 (Rate Period) ASC without New Resource Additions ($/MWh)	**$37.77**	**$37.05**	**$38.08**

C. FY 09 (Exchange Period) ASC with New Resource Additions ($/MWh)

FY 2007-2009 New Resource Additions: N/A
Snohomish had no New Resource Additions.

III. FILING REQUIREMENTS

A. Introduction

Section 5(c)(l) of the Pacific Northwest Electric Power Planning and Conservation Act (Pacific Northwest Power Act), 16 U.S.C. § 839c(c)(l), establishes the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to Bonneville Power Administration (BPA) at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. *See generally*, H.R. Rep. No. 976, Pt I, 96th Cong., 2d Sess. at 60 (1980).

The Act gives BPA's Administrator the discretionary authority to determine ASC on the basis of a methodology to be established in a public consultation proceeding. 16 U.S.C. 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. See 48 FR 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 FR 39,293 (Oct. 5, 1984). In the mid-1990s, BPA and exchanging Utilities agreed to a number of termination agreements that provided for payments to each Utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings.

In 2000, BPA executed REP Settlement Agreements with each IOU customer. The Agreements provided monetary benefits and power sales to the IOUs to resolve disputes regarding BPA's implementation of the REP. On May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit issued a decision finding the Agreements unlawful. BPA therefore began efforts to resume the

REP, including the development of RPSAs and a consultation proceeding to revise the 1984 ASC Methodology.

As with the previous ASC Methodologies, the proposed 2008 ASC Methodology (ASCM) was developed in consultation with interested parties through a series of working group meetings conducted by BPA staff. The goal of the consultation process was to develop an administratively feasible ASC Methodology that would be technically sound, and comport with the Northwest Power Act. The Methodology is subject to review and approval by the Federal Energy Regulatory Commission (FERC or Commission).

BPA maintains a significant role in reviewing Utilities' ASC filings to ensure compliance with the 2008 ASCM. For more information regarding the 2008 ASCM, please refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

For more information regarding the proposed 2008 ASCM, refer to the *Final Record of Decision of the 2008 Average System Cost Methodology*, dated June 30, 2008.

B. ASC Determination Process Guidelines and Expedited Review Process

The purpose of BPA's expedited review process is to estimate exchanging Utilities' ASCs for FY 2009 that could be noticed by the Administrator and incorporated into BPA's WP-07 Supplemental Rate Proceeding in order to ensure that BPA's FY 2009 power rates established in that proceeding rely on the most accurate ASCs possible. For purposes of the expedited review process, and as specified in the Review Procedures of the proposed 2008 ASCM, on or before March 3, 2008, each exchanging utility (Utility) submitted a ''base period ASC'' to BPA using data from its 2006 FERC Form 1 and other supporting data. All data were submitted using BPA's proposed Appendix 1, an Excel-spreadsheet based model. The submittal of the Appendix 1 filing began the formal review and comment process to establish ASCs for the exchanging Utilities which is referred to as the Review Period. Although BPA reviewed the initial data in the context of BPA's initially proposed 2008 ASCM, BPA knew that it would be completing its proposed 2008 ASCM and issuing a Record of Decision supporting that ASCM near the end of June 2008. In order that the ASCs determined in the expedited review process would reflect as accurately as possible the ASCs that would be in effect for determining REP benefits for FY 2009, BPA reviewed the Utilities' filing under the criteria of BPA's Final 2008 ASCM. This ensured that the ASCs relied on by BPA in establishing its FY 2009 power rates would be as accurate as possible. Parties had a full and complete opportunity to intervene in BPA's expedited review process and to submit comments on BPA's proposed ASCs.

For details of the prospective Review Period and guidelines, see *Attachment A to the 2008 Final Record of Decision of the 2008 Average System Cost Methodology, June 2008: 2008 Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange Program Established by Section 5(c) of the Pacific Northwest Electric Power and Conservation Act.*

The 2008 ASCM incorporates, in part, the functionalization process and functionalization codes, with modifications, determined in the 1984 ASCM. Costs are assigned under functionalization codes to Production, Transmission, or Distribution/Other. Functionalization of each Account included in a Utility's ASC is in accordance to the functionalization prescribed in the 2008 ASCM, Attachment A, Table 1.
The ASCM allows Utilities to file multiple, contingent, ASCs to reflect changes to service territories, and allows for changes to ASCs resulting from major resource additions and reductions.

In summary, BPA reviewed ASCs during the expedited review process in accordance with the 2008 ASCM published June 30, 2008. After establishing a base period ASC determination, BPA used the ASC Forecast model, an excel based spreadsheet, to escalate the base year ASC forward to the effective rate period, FY 2009 (October 1, 2008 through September 30, 2009). The base year and forecast ASC results are reported herein.

C. Explanation of Schedules

Utilities' Appendix 1 filings consist of a series of seven schedules and other supporting information, which present the data necessary to calculate ASC. The schedules and support data are as follows:

1. Schedule 1 - Plant Investment/Rate Base
2. Schedule 1A - Cash Working Capital calculation
3. Schedule 2 - Capital Structure and Rate of Return
4. Schedule 3 - Expenses
5. Schedule 3A - Taxes
6. Schedule 3B - Other Included Items
7. Schedule 4 - Average System Cost
8. Distribution of Salaries and Wages
9. Purchased Power & Off-System Sales
10. New Large Single Load
11. Labor Ratios

1. Schedule 1 – Plant Investment/Rate Base

This schedule establishes the rate base used by the Utility. The calculation begins with a determination of the total Electric Plant In-Service, which includes the gross historical costs of the Intangible, General, Production, Transmission, and Distribution Plants. These values (and all subsequent values) are entered into the Appendix 1 filing as line items based on separate FERC account descriptions. Each line item (Account) is functionalized to Production, Transmission, or Distribution/Other in accordance to the functionalizations prescribed in the 2008 ASCM, Attachment A, Table 1.

Next, in order to reflect the book value of the remaining plant, depreciation and amortization reserves are evaluated and entered into the Appendix 1 form and functionalized. These are then subtracted from the Total Electric Plant In-Service to determine the Total Net Plant.

The resulting Total Net Plant is adjusted, where appropriate, to reflect additions in Cash Working Capitol (calculated in Schedule 1A), Utility Plant, Property and Investments, Current and Accrued Assets, Deferred Debits. It is adjusted again, where appropriate, to deduct the Current and Accrued Liabilities, and Deferred Credits from the Total Net Plant. The outcome of these adjustments defines the Total Rate Base. When multiplied by the Rate of Return as determined in Schedule 2, the result is the Utility's return on investment.

2. Schedule 1A – Cash Working Capital

Cash working capital is a ratemaking convention that is not included in the Form 1, but a part of all electric utility rate filings as a component of rate base. To determine the allowable amount of cash working capital in rate base for a Utility, BPA allows 1/8 of the functionalized costs of total production expenses, transmission expenses and Administrative and General expenses less purchased power, fuel costs, and public purpose charge.

3. Schedule 2 – Capital Structure and Rate of Return

This schedule lists the data used by the Utility to develop the rate of return applied to the Utility's rate base developed on Schedule 1 to determine the Utility's return on investment.

IOUs use the weighted cost of capital (WCC) from the most recent State Commission Rate Order with a Federal income tax adjustment to determine the return calculation. The return on equity (ROE) used in the WCC calculation is grossed up for Federal income taxes at the marginal Federal income tax rate using the formula found in the ASC Methodology, Attachment A, Section IX, Endnote b. For COUs, the rate of return is equal to the COU’s weighted cost of debt.

4. Schedule 3 – Expenses

This schedule represents operations and maintenance expenses for the production of power, the transmission of electricity, and the distribution of electricity. Each expense item is functionalized as described above. Additional expenses associated with customer accounts, sales, and administrative and general expenses for both operations and maintenance are also included in this schedule. Depreciation and amortization for the associated plants are added to the operating and maintenance expenses to calculate Total Operating Expenses.

5. Schedule 3A – Taxes

This schedule presents allowable ASC cost for Federal employment tax and non-Federal taxes, including property and unemployment tax. State income tax, franchise fees, regulatory fees, and city/county taxes are included herein but are functionalized to Distribution/Other and therefore not incorporated in ASC. Taxes and fees for each state listed are grouped together and entered as “combined” line items for Appendix 1 filing purposes.

Federal income taxes included in ASC are calculated and described in Schedule 2 above, *Capital Structure and Rate of Return*.

6. Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity to others (wheeling). Items in this schedule are deducted from the total costs of each Utility.

7. Schedule 4 – Average System Cost ($/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Federal income tax adjusted return on rate base, total operating expenses, state and other taxes, and other included items. The schedule also lists the load information, as defined below, and calculates the Utility's ASC.

Contract System Cost:
The Contract System Cost is the Utility's costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. Costs to serve NLSL are excluded from ASC calculations. This Contract System Cost becomes the numerator in calculating ASC.

Contract System Load:
The Contract System Load is the total regional retail load included in the Form 1, or for a consumer-owned utility (preference customers) the total retail load from the most recent annual audited financial statement as adjusted pursuant to this Average System Cost Methodology. The denominator in the ASC calculation consists of the Contract System Load (MWh) of the Utility increased for distribution losses, and reduced by any New Large Single Load(s) (NLSL).

8. Distribution of Salaries and Wages

The supporting file is used to determine the Labor Ratio calculations and includes salaries and wages from relevant operations and maintenance of the electric plant.

9. Purchased Power and Sales for Resale

The Purchased Power is an Account of Schedule 3, *Expenses*, and includes all purchases the Utility made during the year, including power exchanges. Sales for Resale is an Account of Schedule 3B*, Other Included Items,* and includes power sales to purchasers other than ultimate consumers. Listed in the information for both Accounts is the statistical classification code for all transactions. Refer to the FERC Form 1, pages 310-311 for Sales for Resale and pages 326-237 for Purchased Power for identification of the classification codes.

10. New Large Single Load

A new large single load (NLSL) is any load associated with a new facility, an existing facility or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and will result in an increase in power requirements of the specific customer of ten average megawatts (10aMW) or more in any consecutive twelve-month period.

BPA determines the cost of serving NLSLs by using the fully allocated cost of all post-September 1, 1979, resources and long-term power purchases greater than five years in duration.

11. Labor Ratios

These ratios assign costs on a pro rata basis using salary and wage data for production, transmission, and distribution/other functions included in the Utility's most recently filed Form 1. For consumer-owned utilities, comparable data is used based on the cost of service study used as the basis for retail rates at the time of review.

D. <u>ASC Forecast</u>

The Base Period ASC is applied to an Excel-based forecasting model to escalate the Base Year ASC data forward to the Exchange Period. For purposes of the expedited process, that Exchange Period is FY 2009. BPA uses Global Insight's (or its successor) forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA's forecast of market prices for IOU purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. For additional background on the determination of Exchange Period ASCs, see details of the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A.

1. Forecast Contract System Costs

Forecast Contract System Costs (CSC) are the Utility's forecast costs for production and transmission resources, including power purchases and conservation measures, which costs are includable in and subject to the provisions of Appendix 1. As outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection A, Forecast CSC, BPA escalates base period costs to the midpoint of the fiscal year for the FY 2009 rate period/Exchange Period to calculate Exchange Period ASCs. BPA projects the costs of power products purchased from BPA using BPA's forecast of prices for its products.

2. Forecast of Sales for Resale and Power Purchases

BPA does not normalize short-term purchases and sales for resale. The short-term purchases and sales for resale for the Base Period are used as the starting values for the forecast. The Utilities are then allowed to include new plant additions and use a Utility-specific forecast for the (1) price of purchased power and (2) sales for resale price, to value purchased power expenses and sales for resale revenue. For details, see the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection B.

3. Forecast Contract System Load and Exchange Load

All Utilities are required to provide a forecast of their Contract System Load and associated Exchange Load, as well as a current distribution loss study as described in the 2008 ASCM, Attachment A, endnote e/, with their Appendix 1 filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through 4 years after the Exchange Period. The load forecast for Contract System Load and Exchange Load is provided on a monthly basis for the Exchange Period.

4. Major Resource Additions

BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange Period Average System Cost*, Subsection C to determine the change in ASC due to major new resource additions or reductions, subject to meeting the materiality threshold of 2.5%. These additions include new production resource investments, new generating resource investments, new transmission investments, long-term generating contracts, pollution control and environmental compliance investments relating to generating resources, transmission resources or contracts, hydro relicensing costs and fees, and plant rehabilitation investments.

The exchanging Utility provides its forecast of any major resource addition and all associated costs. The forecast covers the period from the end of the Base Period (FY 2006) to the end of the Exchange Period (FY 2009).

The forecast of the major resource costs to be included in the Utility's Exchange Period ASC is reviewed and determined during the review period. All resources included prior to the start of the Exchange Period are projected forward to the mid-point of the Exchange Period.

5. Load Growth Not Met by New Resource Additions

All load growth not met by new resource additions is met by purchased power at the forecasted Utility-specific short-term purchased power price. BPA uses the method outlined in the 2008 ASC Methodology, Section IV *Rules for Determining Exchange*, Subsection D.

IV. REVIEW OF THE ASC FILING

A. Identification and Analysis of Issues from the May 7, 2008 ASC Appendix 1 Filing

BPA is responsible for reviewing all costs and loads for determining ASCs in accordance with section 5(c) of the Northwest Power Act and the 2008 ASC Methodology. During this review and evaluation, issues were identified for comment. BPA's ASC determination is limited to specific findings on those issues identified for comment with the exception of ministerial or mathematical errors. There may have been additional issues that BPA did not identify for comment in this filing. Acceptance of a Utility's treatment of an item without comment is not intended to signify a decision of the proper interpretation to be applied either in subsequent filings or universally under the 2008 ASC Methodology.

The following is a summary of the Contract System Costs and codes filed on May 7, 2008 by Snohomish PUD (PSE), and as amended following review and evaluation by BPA. The explanations for BPA's changes are outlined as appropriate by Appendix 1 schedule and supporting files below.

SCHEDULE 1: Plant Investment/Rate Base

1. **Account 303 Intangible Plant Miscellaneous - Transmission**

    a. Statement of Issue: In the May 7th filing, Snohomish PUD used Direct Analysis to functionalize this Account 303 Intangible Plant Miscellaneous, without supplying adequate support for the direct analysis.

    b. Statement of Facts: Account 303 Intangible Plant Miscellaneous sub accounts are to be functionalized using Direct Analysis with a default functionalization of Distribution.

    c. Snohomish PUDs Response to the Issue: Misc. Int. Plt. 3rd AC Intertie 303101 $8,981,368 RATE BASE Trans - This account records the PUDs ownership rights to the 3rd AC Intertie, a transmission line.

    Misc. Int. Plt. N Mtn SCL Pwr Xfr 303102 $2,809,844 RATE BASE Trans - Represents the PUDs ownership rights in the North Mountain substation owned by Seattle city light and used to serve customers in the Darrington area. This provides access to SCLs transmission.

    Misc. Int. Plt. BPA NERC Reliably 303103 $1,577,113 RATE BASE Trans - This represents the PUDs ownership rights to equipment in a BPA substation that the PUD is required to own to meet NERC reliability requirements

    - Intangible Plt. Software 5 YR 304101 $5,363,429
    - Intangible Plt. Software 8 YR 304102 $27,498,255
    - Int. Plt. Software Beyd Est. Life 304110 $15,748,189

    See Worksheet "Snohomish PUD – Data Responses" Tab SN-1 for analysis of these accounts and functionalization. Please note that during this analysis, we have identified items in these accounts which should be functionalized differently than in our original analysis.

    d. Analysis of Position and Decision: Snohomish PUD has provided sufficient information to support the functionalization of Account 303 Intangible Plant Miscellaneous.

2. **Account 124 Other Investment**

    a. Statement of Issue: In the May 7th filing, Snohomish PUD directly functionalized this account using the Cons ratio, without showing the basis of the direct assignments.

b. Statement of Facts: Account 123 Other Investment has a Direct Distribution functionalization. In addition, the Cons Ratio is no longer in use. Conservation is functionalized using Direct Analysis.

c. Snohomish PUDs Response to the Issue:

- Other Inv Coml Consv Loan 124101 $8,029
- This account records our investment in commercial Conservation loans. Conservation costs are functionalized to production per methodology endnote g.

- Other Inv Resd Consv Loan 124102 $6,961,357
- This account records our investment in residential Conservation loans. Conservation costs are functionalized to production per methodology endnote g.

- Other Inv Pwr Diversion* 124104 $4,729
- This account records a receivable from customers who have to pay back the district for theft of power.

- Other Inv Line Ext Loan* 124105 $17,344
- This account records a receivable from customers to connect a property to our grid.

- Other Inv Spec Arrangement Loans* 124107 $400 - This account records loans to customers, who, due to a meter misread have a large payable to the utility.

*Please note that during this analysis, we have identified that these items should be functionalized to Distribution/Other rather than Production.

d. Analysis of Position and Decision: Snohomish PUD used CONS ratio that functionalizes 70% to Production and 30% to Distribution. In the response to the issue, Snohomish PUD showed that $7,218,741 was directly conservation investments. The remainder of the account is distribution related.

BPA will functionalize $6,969,386 of Account 124 Other Investments to Production. The remaining $22,474 will be functionalized to Distribution. In the October 1, 2008 ASC Filing this issue will be addressed.

3. **Account 186 Deferred Debits – Production Related**

a. Statement of Issue: In the May 7th filing, Snohomish PUD directly functionalized Account 186 Deferred Debits using Direct Analysis without showing the basis of the direct assignments.

b. Statement of Facts: Account 186 Deferred Debits sub accounts are to functionalized using Direct Analysis with a default functionalization of Direct Distribution.

c. Snohomish PUDs Response to the Issue: Snohomish PUD provided the following information for the functionalization of sub accounts to Production.

- Misc. Def Debit Conservation 186114 $4,998,403
- Capitalized conservation costs. Conservation costs are allocated to production per methodology endnote g.

- Misc. Def Debit JK Re-license 186122 $2,650,137
- Capitalized relicensing costs for the Jackson Hydro Plant – Generation system costs are allocated to Production.

- Misc. Def Debit Int. Rate Swaps 186125 $18,877,515
- Mark to Market costs for Generation system long term debt. Generation system costs are allocated to Production.

- Misc. Def Debit Enron Contract 186123 $149,293,458
- Represents our potential obligation to a long – term power contract. There is a corresponding 253 credit account.

- Misc. Def Debit Est. Jackson Pwr 186107 $4,410,000
- This is an electric system receivable for Jackson Hydro Plant operations. Generation system costs are allocated to production.

- Misc. Def Debit Other Gen 186108 $2,300,000
- This is an electric system receivable for Other Generation Operating expenses. Generation system costs are allocated to production.

- Misc. Def Debit Everett Cogen. 186110 $296,000
- This is an electric system receivable for Other Generation Operating expenses. Generation system costs are allocated to production.

- Misc. Def Debit Power Contracts 186124 $198,825

d. Analysis of Position and Decision: Snohomish PUD has provided sufficient information to support the direct functionalization of Account 186 Deferred Debits.

4. **Account 243 Deferred Credits**

a. Statement of Issue: In the May 7th filing, Snohomish PUD directly functionalized this account without showing the basis of the direct assignments.

b. Statement of Facts: Account 243 - Deferred Credits sub accounts are to functionalized using Direct Analysis with a default functionalization of Direct Distribution.

c. Snohomish PUD's Response to the Issue: Snohomish PUD provided the following information for the functionalization of sub accounts to Production.

- Other Def Cr Enron Contract 253140 $149,293,458
- Represents our potential obligation to a long – term power contract. There is a corresponding 186 debit account. Power costs/credits are functionalized to Production.

- Def Cr Adv Revenue EC 253116 $712,910
- This is a generation system account which records advance revenue for the Everett Cogeneration Plant. Generation expenses/revenues are allocated to Production.

- Other Def Cr Adv Revenue JK 253118 $2,568,963
- Same as above for the Jackson Hydroelectric Plant

- Other Def Cr Adv Revenue OG 253119 $1,169,649
- Same as above for Other Generation.

d. Analysis of Position and Decision: Snohomish PUD has provided sufficient information to support the direct functionalization of Account 186 Deferred Debits.

SCHEDULE 1A: Cash Working Capital – no changes

SCHEDULE 2: Capital Structure and Rate of Return – no changes

SCHEDULE 3:

1. **Public Purpose Charge**

a. Statement of Issue: In its May 7th filing, Snohomish PUD included 7,218,741 in the Public Purpose Charge line item and functionalized this cost using the CONS ratio.

b. Statement of Facts: The Public Service Charge line item relates to the Oregon Public Purpose charge and is to be functionalized using Direct Analysis. For all conservation costs, the utility is to use Direct Analysis as the method for supporting the functionalization of conservation

c. Snohomish PUD's Response to the Issue: Snohomish PUD provided the following information for the functionalization of sub accounts to Production.

Expense Accounts

Account	Project	DESCR	SumOfSum Total Amt	Qualifies??
583102	00340398	CVR / NEEA LOAD RESEARCH	$ 112.97	*Yes*
583102	00345751	2005 GENERAL CVR - CONSERVATIO	$ 594.05	*Yes*
583102	00346261	BRIER SUB CVR UPDATES	$ 155.07	*Yes*
583102	00348134	CLEARVIEW SUBSTATION CVR MAINT	$ 6,160.23	*Yes*
583102	00349345	CLEARVIEW SUBSTATION CVR MAINT	$ 714.33	*Yes*
583102	00349346	CLEARVIEW SUBSTATION CVR MAINT	$ 5,893.19	*Yes*
583102	00350495	2006 GENERAL CVR - CONSERVATIO	$ 12,820.92	*Yes*
583102	00351576	2006 LAKE STEVENS CVR CONVERSI	$ 175.70	*Yes*
583102	00351980	LYNNWOOD CVR UPDATES	$ 1,343.45	*Yes*
583102	00351981	2006 MEADOWDALE CVR UPDATE	$ 1,225.77	*Yes*
583102	00351982	2006 MEADOWDALE CVR UPDATE	$ 7,981.13	*Yes*
583102	00352417	TULALIP CVR UPDATES	$ 2,564.02	*Yes*
583102	00352422	KELLOGG MARSH CVR UPDATES	$ 10,331.84	*Yes*
583102	00352424	HILTON LAKE CVR APPLICATION	$ 5,008.65	*Yes*
583102	00352835	CLEARVIEW SUBSTATION CVR MAINT	$ 1,610.74	*Yes*
583102	00353439	SNOHOMISH CVR MAINTENANCE	$ 8,182.97	*Yes*
583102 Total			**$ 64,875.03**	***Yes***
584102	00345751	2005 GENERAL CVR - CONSERVATIO	$ 76.93	*Yes*
584102	00350495	2006 GENERAL CVR - CONSERVATIO	$ 1,660.45	*Yes*
584102 Total			**$ 1,737.38**	***Yes***
586101	60024	Other C&I Services	$ 39,549.69	*Yes*
586101	00339361	SULTAN CVR - PLANNING, DESIGN	$ 4,008.52	*Yes*

Expense Accounts				
Account	Project	DESCR	SumOfSum Total Amt	Qualifies??
586101	00340398	CVR / NEEA LOAD RESEARCH	$ 2,206.10	*Yes*
586101	00345751	2005 GENERAL CVR - CONSERVATIO	$ 428.90	*Yes*
586101	00350495	2006 GENERAL CVR - CONSERVATIO	$ 9,256.88	*Yes*
586101 Total			**$ 55,450.09**	***Yes***
588101	00352065	SUBSTATION CAPACITOR APPLICATI	$ 151.12	*Yes*
588101 Total			**$ 151.12**	***Yes***
593101	00351576	2006 LAKE STEVENS CVR CONVERSI	$ 439.95	*Yes*
593101 Total			**$ 439.95**	***Yes***
594101	00352388	CUSTOMER GENERATION XMER DECAL	$ 140.97	*Yes*
594101 Total			**$ 140.97**	***Yes***
901101	60058	Conservation Administration	$ 352.91	*Yes*
901101	60059	NEEA Conservation	$ 15.57	*Yes*
901101 Total			**$ 368.48**	***Yes***
903101	60058	Conservation Administration	$ 209.60	*Yes*
903101 Total			$ 209.60	*Yes*
907101	60017	Public Purpose Development	$ 970.27	*Yes*
907101	60058	Conservation Administration	$ 2,193.07	*Yes*
907101	60059	NEEA Conservation	$ 594.00	*Yes*
907101 Total			**$ 3,757.34**	***Yes***
908101	60016	Customer Account Activities	$ 150.00	*Yes*
908101	60017	Public Purpose Development	$ 188,365.86	*Yes*
908101	60024	Other C&I Services	$ 3,152,363.99	*Yes*
908101	60025	Consv Loans Program	$ 22,791.56	*Yes*
908101	60039	Schools and Public Bldgs.	$ 1,879.73	*Yes*
908101	60040	Matchmaker	$ 353,361.99	*Yes*
908101	60041	Appliance Rebates	$ 895,427.39	*Yes*
908101	60042	Compact Florescent Light Prog	$ 858,869.84	*Yes*
908101	60044	C&I Benchmarking	$ 3,258.79	*Yes*
908101	60045	New Construction-Commercial	$ 5,027.59	*Yes*
908101	60046	New Construction-Residential	$ 28,963.43	*Yes*
908101	60050	Vendor Miser Energy Efficiency	$ 1,969.41	*Yes*
908101	60052	Residential Heat Pump Incentiv	$ 57,000.00	*Yes*
908101	60053	Retail Green Power Planet Pwr	$ 82,463.18	*Yes*
908101	60056	Housing Improvement Prgm (HIP)	$ 322,068.99	*Yes*
908101	60058	Conservation Administration	$ 235,925.22	*Yes*
908101	60059	NEEA Conservation	$ 183,167.08	*Yes*

Expense Accounts

Account	Project	DESCR	SumOfSum Total Amt	Qualifies??
908101	60060	Consv Cust Acct Activities	$ 32,165.33	*Yes*
908101	60061	Customer Renewables	$ 1,548.46	*Yes*
908101	60063	Refrigerator Recycle Program	$ 530,854.06	*Yes*
908101	60064	Seattle Fndtn Mobile Home Prog	$ 47,504.33	*Yes*
908101	60066	Biodigester - Qualco Energy	$ 4,680.68	*Yes*
908101	66005	Verify, Evaluate Measurement	$ 27,358.08	*Yes*
908101	00327985	PLANET POWER MARKETING	$ 32,163.83	*Yes*
908101	00327986	PLANET POWER IMPLEMENTATION	$ 3,513.96	*Yes*
908101	00328396	SERVICES TOR SNOHOMISH SCHOOL	$ 3,683.95	*Yes*
908101	00328397	SERVICES TOR MARYSVILLE SCHOOL	$ 3,185.77	*Yes*
908101 Total			**$ 7,079,712.50**	***Yes***
909101	60053	Retail Green Power Planet Pwr	$ 1,815.98	*Yes*
909101 Total			**$ 1,815.98**	***Yes***
913101	60063	Refrigerator Recycle Program	$ 261.00	*Yes*
913101 Total			**$ 261.00**	***Yes***
920101	60066	Biodigester - Qualco Energy	$ 9,490.31	*Yes*
920101 Total			**$ 9,490.31**	***Yes***
921101	60017	Public Purpose Development	$ 330.75	*Yes*
921101 Total			$ 330.75	Yes
Grand Total			$ 7,218,740.50	

d. Analysis of Position and Decision: The information provided by Snohomish PUD supports the functionalization of the Public Purpose Charge with 70% functionalized to Production and 30% functionalized to Distribution.

In the October 1, 2008 ASC filing all conservation costs will be functionalized using Direct Analysis.

2. **Account 404 - Amortization of Intangible Plant Miscellaneous**

a. Statement of Issue: In its May 7th filing, Snohomish PUD functionalized Account 404 – Amortization of Intangible Plan Miscellaneous using Direct Analysis, without sufficient information to support the functionalization.

b. Statement of Facts: Functionalization using Direct Analysis for Account is required. The default functionalization is Direct Distribution. Direct

Analysis must be supported with sufficient details of the account and justification of the functionalization.

c. Analysis of Position and Decision: Snohomish PUD did not respond to the issues list regarding the use of Direct Analysis for Account 404-Anirtuzation of Intangible Plant Miscellaneous.

In the October 1, 2008 ASC filing the use of Direct Analysis will be accompanied by sufficient information to support the proposed functionalization of Account 404-Anirtuzation of Intangible Plant Miscellaneous.

SCHEDULE 3A: Taxes – no changes

SCHEDULE 3B: Other Included Items – no changes

1. **Sales for Resale MWhs**

a. Statement of Issue: In its May 7th filing, Snohomish PUD did not provide the Sales for resale MWhs value in ASC Template.

b. Statement of Facts: Snohomish provided the MWhs.

c. Analysis of Position and Decision: Adjusted the Sales for Resale to reflect 2,105,474 MWhs

SCHEDULE 4: Average System Cost

1. **Distribution Loss:**

a. Statement of Issue: In its May 7th filing, Snohomish PUD used a 5% Distribution Loss Factor in determination of its ASC.

b. Statement of Facts: The May 7th filing Appendix 1 template did not require a Utility to complete a Distribution Loss Study to increase the Total Retail Load. As outlined in the ASCM ROD, BPA allows participating Utilities that have the ability to directly measure distribution losses on their system to submit such measurements, subject to BPA review and approval, with their ASC filings. Utilities that do not possess the capability to directly measure distribution losses on their system are required to submit a formal distribution loss study with their ASC filing. The distribution loss study is valid for a period of seven years. Utilities that do not have the ability to directly measure distribution losses on their system and do not have a formal distribution loss study that was prepared within the previous seven years of the date of the ASC filing will use the default distribution loss study method described in the ASCM ROD, Section 4.10.5.

c. Analysis of Position and Decision: For purposes of the expedited filing, BPA was unable to provide a Distribution Loss Study. BPA will use the 5% Distribution Loss Factor that was included in Snohomish PUD's May 7th filing.

2. **Contract System Loads:** New Large Single Load (NLSL) – None - No changes

3. **Contract System Costs:** New Large Single Load (NLSL) Costs - None- No changes

SUPPORTING DOCUMENTATION: Purchased Power and Sales for Resale – no changes

SUPPORTING DOCUMENTATION: Salaries and Wages – no changes

SUPPORTING DOCUMENTATION: Labor Ratios

1. **Maintenance of General Plant (GPM) Ratio:** Miscellaneous Equipment

   a. Statement of Issue: Incorrect functionalization of Labor Ratio "Miscellaneous Equipment in the Maintenance of General Plant (GPM)"

   b. Statement of Facts: Miscellaneous Equipment in the Maintenance of General Plant Ratio was mistakenly functionalized to Distribution rather than PTD in the ASC Template.

   c. Analysis of Position and Decision: BPA corrected the error and the functionalization of Miscellaneous Equipment in the Maintenance of General Plant Ratio was changed from Distribution to PTD in the ASC Template.

B. Identification and Analysis of Issues from comments to the July 8, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base– no changes from July 8, 2008 report

SCHEDULE 1A: Cash Working Capital – no changes from July 8, 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from July 8, 2008 report

SCHEDULE 3: – no changes from July 8, 2008 report

SCHEDULE 3A: Taxes – no changes from July 8, 2008 report

SCHEDULE 3B: Other Included – no changes from July 8, 2008 report

SCHEDULE 4: Average System Cost - – no changes from July 8, 2008 report

SUPPORTING DOCUMENTATION – no changes from July 8, 2008 report

C. Identification and Analysis of Issues from comments to the August 4, 2008 ASC Draft Report

SCHEDULE 1: Plant Investment/Rate Base–

1. For Account 108, line item "**Capital Leases - Common Plant"** and **In-Service: Depreciation of Common Plant**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 108, line item "**Capital Leases - Common Plant"** (line 69 in the electronic template) and "**In-Service: Depreciation of Common Plant (a)"** (line 71 in the electronic template), remove the **PTD** option from functionalization "Method Optional" column.

   b. Analysis of Position and Decision: This correction is necessary to equate all Common Plant accounts to DIRECT functionalization under **Utility Plant: Common Plant** (line 91 in the electronic template). There are no functionalization options under Common Plant and all accounts are to be functionalized by Direct analysis.

2. For Account 115, line item "**Amortization of Acquisition Adjustments**

   a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 115, line item "**Amortization of Acquisition Adjustments** (line 73 in the electronic template), remove option from functionalization "Method Optional" column (cell F73 in electronic template) and equate cell E73 to E92 (**Acquisition Adjustments** (**Electric)**, Account 114, line 92 in electronic template).

   b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization Reserves must follow the same functionalization used for Utility Plant under Assets and Other Debits.

SCHEDULE 1A: Cash Working Capital – no changes from the August 4 2008 report

SCHEDULE 2: Capital Structure and Rate of Return – no changes from the August 4 2008 report

SCHEDULE 3: – Expenses

1. For Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)**

    a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 406, line item "**Amortization of Plant Acquisition Adjustments (Electric)** (line 96 in the electronic template), equate cell E96 to Account 114 **Schedule 1, *Plant Investment/Rate Base*** **(Acquisition Adjustments (Electric)**, (cell E92 in electronic template).

    b. Analysis of Position and Decision: This correction is necessary because Depreciation and Amortization expenses must follow the same functionalization used for Utility Plant under Plant Investment/Rate Base, Assets and Other Debits.

2. Account 908, line item "**Customer Assistance Expenses (Major only)**"

    a. Statement of Issue: Errata corrections to the 2008 Average System Cost Methodology ("2008 ASCM") for Account 908, line item "**Customer Assistance Expenses (Major only)**" (line 52 in the electronic template) requires DIRECT analysis of conservation related expenses:

    b. Analysis of Position and Decision: All exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

SCHEDULE 3A: Taxes – no changes from the August 4 2008 report

SCHEDULE 3B: Other Included – no changes from the August 4 2008 report

SCHEDULE 4: Average System Cost - – no changes from the August 4 2008 report

SUPPORTING DOCUMENTATION – Labor Ratios

1. For Labor Ratio Input: line item "**Customer Service and Informational**"

   a. Statement of Issue: For Labor Ratio Input: line item "**Customer Service and Informational**" (line 17 in the electronic template), did not follow the same functionalization as Account 908 in Schedule 3.

   b. Analysis of Position and Decision: This Ratio requires DIRECT analysis of conservation related expenses associated with Account 908: all exchangeable conservation costs may be functionalized to Production (PROD); all other costs will be functionalized to Distribution/Other (DIST).

D. Exchange Period ASC New Resource Additions

The ASCM provides that changes to an established ASC are allowed to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet that Utility's retail load during the BPA rate period. The change in ASC must meet the materiality threshold as the change in ASC resulting from adding major new resources, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows Utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more. Snohomish did not have any New Resource Additions.

V. FINAL EXPEDITED ASC FORECAST for FY 2009-2013

The following three tables summarize the forecast of Contract System Cost (CSC) and Contract System Load (CSL) for purposes of determining Snohomish County PUD forecast ASCs for FY 2009 through FY 2013. Table 2: *FY 2009-2013 ASC Summary,* identifies the CSC, CSL, and Snohomish County PUD ASCs published in the July 8, 2008 report. *Revised* Table 2: *FY 2009-2013 ASC Summary* identifies the revised CSC, CSL, and Snohomish County PUD ASCs as appropriate and as a result of Snohomish County PUD comments to the July 8, 2008 report. *Final* Table 2: *FY 2009-2013 ASC Summary* identifies the final CSC, CSL, and Snohomish County PUD ASCs. The procedures used in making the July 8, 2008, determinations and any required changes published in both the August 4, 2008, and this final September 11, 2008, reports are outlined in the 2008 ASCM ROD and described herein. The results shown in all tables are forecasts for each year of the WP-07 rate test period (FY 2009-2013), as defined in section 7(b)(2) of the NW Power Act, and are used to calculate the PF Exchange Rate for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding (WP-07 Rate Case).

The BPA Forecast Model used to calculate the values shown below is located at http://www.bpa.gov/corporate/finance/ascm/filings.cfm.

Table 2: FY 2009-2013 ASC Summary – July 8, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	237,521,129	237,813,973	249,293,862	261,452,214	264,945,059
Transmission	37,611,796	37,979,200	38,471,842	39,017,404	39,600,659
NLSL Fully Allocated Cost ($/MWh)					
(Less) NLSL Costs	0	0	0	0	0
Total Contract System Cost	**275,132,925**	**275,793,173**	**287,765,704**	**300,469,618**	**304,545,718**

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
(Less) NLSL					
Total Retail Load (Net or NLSL)	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
Distribution Loss	346,873	351,704	354,636	357,506	360,114
Total Contract System Load	**7,284,334**	**7,385,777**	**7,447,346**	**7,507,618**	**7,562,386**

AVERAGE SYSTEM COST

ASC ($/MWh)	**37.77**	**37.34**	**38.64**	**40.02**	**40.27**

Revised Table 2: FY 2009-2013 ASC Summary – August 4, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	232,339,854	244,308,235	247,588,656	260,587,973	263,899,001
Transmission	37,611,796	37,979,200	38,471,842	39,017,404	39,600,659
NLSL Fully Allocated Cost ($/MWh)					
(Less) NLSL Costs					
Total Contract System Cost	269,951,649	282,287,435	286,060,497	299,605,377	303,499,660

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
(Less) NLSL					
Total Retail Load (Net or NLSL)	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
Distribution Loss	346,873	351,704	354,636	357,506	360,114
Total Contract System Load	7,284,334	7,385,777	7,447,346	7,507,618	7,562,386

AVERAGE SYSTEM COST

ASC ($/MWh)	37.06	38.22	38.41	39.91	40.13

Final Table 2: FY 2009-2013 ASC Summary – September 11, 2008

Date (mid-year)	**4/1/2009**	**4/1/2010**	**4/1/2011**	**4/1/2012**	**4/1/2013**
Fiscal Year	**2009**	**2010**	**2011**	**2012**	**2013**

CONTRACT SYSTEM COST

Production	239,609,815	254,546,263	257,833,058	274,327,600	277,644,989
Transmission	37,780,520	38,148,568	38,641,922	39,188,191	39,772,181
NLSL Fully Allocated Cost ($/MWh)					
(Less) NLSL Costs					
Total Contract System Cost	277,390,335	292,694,831	296,474,980	313,515,790	317,417,170

CONTRACT SYSTEM LOAD

Total Retail Load @ Meter	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
(Less) NLSL					
Total Retail Load (Net or NLSL)	6,937,461	7,034,074	7,092,711	7,150,113	7,202,273
Distribution Loss	346,873	351,704	354,636	357,506	360,114
Total Contract System Load	7,284,334	7,385,777	7,447,346	7,507,618	7,562,386

AVERAGE SYSTEM COST

ASC ($/MWh)	**38.08**	**39.63**	**39.81**	**41.76**	**41.97**

VI. BPA STATEMENT

This ASC determination is BPAs best estimate of Snohomish's FY 2009 ASC based on the information and data provided from Snohomish during the Expedited Review Process, and based on the professional review, evaluation, and judgment of the BPA REP staff. Decisions made herein are not binding for purposes of the Final ASC determination for FY 2009. This determination is made solely for the purpose of providing estimated FY 2009 ASCs for use in the development of BPAs FY 2009 power rates in BPAs WP-07 Supplemental Rate Proceeding. Decisions made herein are not final ASC determinations for purposes of implementing the REP for FY 2009. Final ASC determinations used to calculate REP benefits for each exchanging Utility for FY 2009 will be established by BPA after a review of such Utilities' October 1, 2008, Appendix 1 filings. Such reviews will be conducted in compliance with the Final 2008 ASC Methodology.

BPA has resolved the issues set forth in Section III of this report, as amended, in accordance with the 2008 Average System Cost Methodology (ASCM) as it is currently described in the Final Record of Decision, and with generally accepted accounting principles. BPA believes the information and data contained herein fairly estimates the Average System of Snohomish for FY 2009 of the WP-07 Supplemental Wholesale Power Rate Adjustment Proceeding.

The Final Appendix 1 Filing, Forecast Model and NLSL assessment used to calculate Snohomish's ASCs can be viewed at BPAs ASC website:
http://www.bpa.gov/corporate/finance/ascm/filings.cfm.